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Article

Hybrid Thermal-Chemical Enhanced Oil Recovery Methods; An Experimental Study for Tight Reservoirs

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Abstract: It is essential to have an adequate understanding of the fluid-structure in a porous medium since this gives direct information about the processes necessary to extract the liquid and the likely yield. The concept of symmetry is one of the petroleum engineering issues that has been used to provide an analytical analysis for modeling fluid dynamics through porous media, which can be beneficial to validate the experimental field data. Tight reservoirs regarding their unique reservoir characterization have always been considered as a challenging issue in the petroleum industries. In this paper, different injectivity scenarios which included chemical and thermal methods were taken into consideration to compare the efficiency of each method on the oil recovery enhancement. According to the results of this experiment, the recovery factor for foams and brine injection is about 80%, while it is relatively 66% and 58% for brine-carbon dioxide and brine-nitrogen, respectively. Consequently, foam injection after water flooding would be an effective method to produce more oil volumes in tight reservoirs. Moreover, KCl regarding its more considerable wettability changes has provided more oil production rather than other scenarios.

Keywords: chemical methods; brine salinity; foam injection; thermal recovery techniques; oil recovery factor

1. Introduction

Unconventional reservoirs have always been considered as one of the essential sources of hydrocarbons in petroleum industries [1–3]. Tight reservoirs are one of the unconventional reservoirs with lower permeabilities, especially those less than 1 mD. Therefore, introducing different techniques and recovery methods was taken into consideration to economically and technically increase the oil production [4–6]. The terms enhanced oil recovery (EOR) and improved oil recovery (IOR) has been used loosely and interchangeably at times [7–9]. IOR is a general term which implies improving oil recovery by any means. For example, operational strategies, such as infill drilling and horizontal wells, improve vertical and areal sweep, leading to an increase in oil recovery [10–12]. In other words, EOR is defined as the injection of those materials (chemical or non-chemical) that have not existed in the reservoir normally, which is covered all types of oil recovery processes such as well treatment, driving forces, and so on with different injectivity agents regarding the reservoir characteristics. Chemical flooding involves a mixture of technologies, as they are more compatible with the reservoir characteristics or regarding their efficiency on special occasions after the secondary recovery methods. EOR techniques consist of thermal flooding (steam (huff and puff drive or steam drive), combustion,

and so on), gas flooding (miscible and immiscible gases that are mainly defined by the injected fluids of nitrogen, carbon dioxide, or flue gas) [13–15].

Boundary conditions are one of the influential issues in the modeling of fluid dynamics of different types of fluid through porous media, which is called a symmetrical issue. Symmetry issues include well boundary conditions, axisymmetric boundary conditions, and symmetric boundary conditions that should be taken into consideration in computational fluid dynamics [16]. Selection of foaming agent should be investigated according to the foam stability, foamability and foam mobility, which is different for each situation, as there are various rock and reservoir characteristics and it should be taken into consideration in the laboratory to provide the best efficiency in recovery performances [17–19]. The characterization of foams is utterly dependent on the size of the bubbles. The foam quality in which the bubble size is defined as the average diameter of the bubbles (it might be varied regarding the properties of the foam and the distribution of the bubbles and for colloidal sizes is about 0.01–0.1 μm) and foam quality is considered as the percentage of the fraction of gas volumes in the generated foam that ranges from 75% to 90% [20–22].

Yu et al. (2015) proposed a numerical method to simulate the carbon dioxide in a tight formation. In their simulation, they considered the molecular diffusion of carbon dioxide, reservoir heterogeneity in the performances of oil production, and the number of cycles in the huff-n-puff process. They concluded that carbon dioxide diffusion played a substantial role in oil recovery improvement from tight reservoirs, which is more adjustable to low permeable zones in these reservoirs [23]. As the proper modelling of complex tight reservoirs such as hydraulic fractures always has a challenging issue in the petroleum industries, Zuloaga-Molero et al. (2016) proposed an embedded discrete fracture model to analytically model the complex fracture geometries and the performances of carbon dioxide injection as a continuous phase. According to their results, accurate modelling of fracture geometries would be a substantial role in oil recovery prediction. Moreover, they provided a new parametric study in permeability and carbon dioxide molecular diffusion in tight reservoirs [24].

Liu et al. (2017) did an experimental evaluation of the displacement efficiency of ZenPing tight oilfield by comparing air injection, liquid foam injection, and air-foam injection performances. According to their results, air-foam injection provided the best performance in tight reservoirs by blocking the fractures, and it would improve the oil recovery. They suggested that it would be better to start the air-foam injection before the water cut reached its highest value of 90% [25]. Alharthy et al. (2018) proposed a numerical and experimental evaluation to consider different gas components of nitrogen, carbon dioxide, ethane/methane solvents on oil recovery enhancement. They concluded that solvent injection (solvent extraction and miscible injection) of different gases would be preferred as an efficient method in tight reservoirs [26]. Davarpanah and Mirshekari (2018) simulated one of the oil rim reservoirs by drilling new horizontal or vertical wells to improve the oil recovery factor. They concluded that drilling a new horizontal well regarding its greater contact with the reservoir would be an excellent choice to enhance the oil production rate [27].

In this paper, different injectivity scenarios which included chemical and thermal methods were taken into consideration to compare the efficiency of each method on the oil recovery enhancement. Two different brine components of KCl and CaCl_2 were taken into consideration, and it was compared with formation brine. KCl has the most significant wettability change, and it has caused a greater recovery factor. Furthermore, foam injection after water flooding would be an effective method to produce more oil volumes in tight reservoirs.

2. Materials and Methods

2.1. Materials

In this experiment, the core samples were selected from the Bangestan reservoir that is located in the south-west of Iran. The samples' length were 8.24 cm, and their outer diameter was about 4.1 cm. The permeability ranges for these core samples were varied from 0.2 to 0.4 mD. To be more accurate,

the brine was provided in the laboratory due to the actual reservoir characteristics, and brine salinity was being prepared accordingly. The provided brine in this experiment contained KCl, CaCl_2 and formation brine with the salinity of 22,000 ppm to compare the influence of each brine on the recovery. The density and viscosity of crude oil is 1.1 g/cm^3 and 0.0984 cP , respectively. Carbon dioxide and nitrogen were used as an immiscible gas for the core flooding processes. The purity of carbon dioxide and nitrogen is about 99.9%. The properties of each brine are statistically depicted in Table 1.

Table 1. The properties of different brines.

Brine Type	TDS (mg/L)	pH (25 °C)	pH (85 °C)	Density (25 °C) g/cm^3	Density (85 °C) g/cm^3
CaCl_2	500–6000	6.7–7.1	6.5–7	1.0002–1.003	0.98–0.985
KCl	500–6000	6.21–6.68	6.12–6.53	1–1.0025	0.975–0.98
Formation Brine	130000	7.2	7.05	1.025	0.98

Chemicals formula: the foaming agent or surfactant which is used in this experiment is the combination of sodium alpha-olefin sulfate (that is known as AOS (C14–16) with the active matter of 35%. To obtain the relevant results for this investigation, different shear rates, e.g., 5 to 500 sec^{-1} , were applied for the foaming agent. Thereby, the average apparent viscosity for the foaming agent is measured about $345 \text{ mPa}\cdot\text{sec}$.

2.2. Core Flooding

The components of the core flooding equipment contained the core holder, which was supplied with the various fluids by displacement pumps that were located in the horizontal section. Then, the core plug was placed through the core holder to allow the fluids at the input or output at determined pressure and temperature. To prevent the core surface curve, the confining pressure was 2600 psi, which was assumed to be 500 psi more than the core fluid pressure. The operational temperature which was used in this experiment was 60°C to be more adapted with the reservoir circumstances. To confirm the propagation of foam through the samples, in the outlet of the producer, one transparent tube was put to record the foam flow. The schematic of the core flooding setup which was used in this experiment is shown in Figure 1.

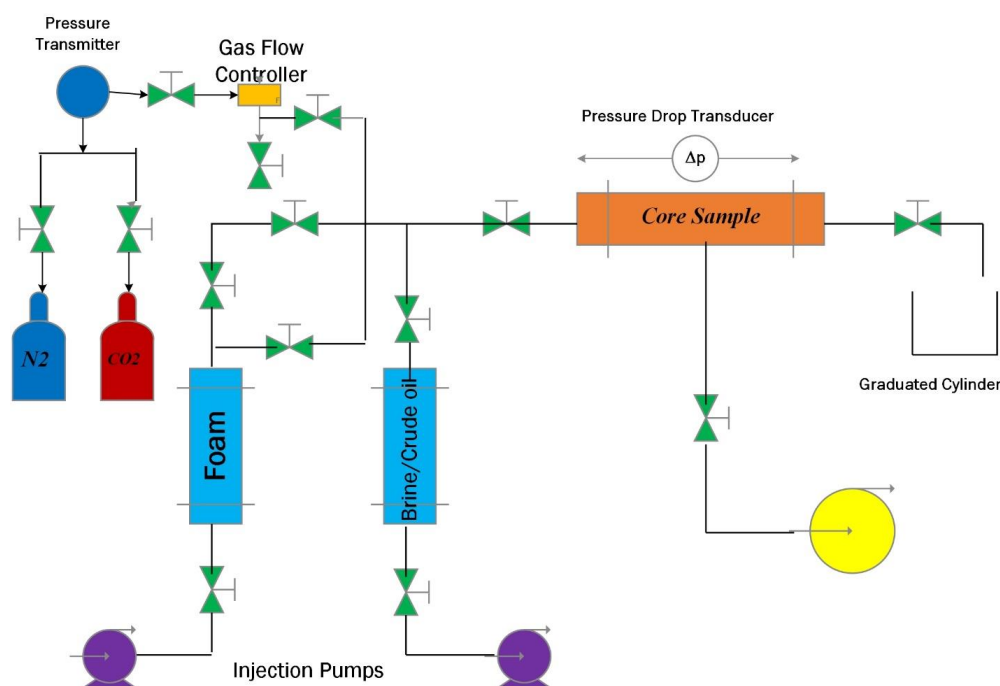


Figure 1. Schematic of core flooding experiment.

3. Results and Discussion

3.1. Mobility Ratio

The relative mobility for both waterflooding and foam flooding with the foam quality of 80% is schematically depicted in Figure 2. As can be seen in Figure 2, the lowest relative mobility for waterflooding methods is about 0.012 mD/cP. However, it is reduced up to its minimum value of 0.007 for foam flooding performances. As tight reservoirs have extremely low permeability compared to other conventional reservoirs, it is witnessed that foams performed as the mobility adjustment substance. Therefore, it is indicated that foams would play a substantial role in mobility reduction in tight reservoirs and improving the oil recovery factor.

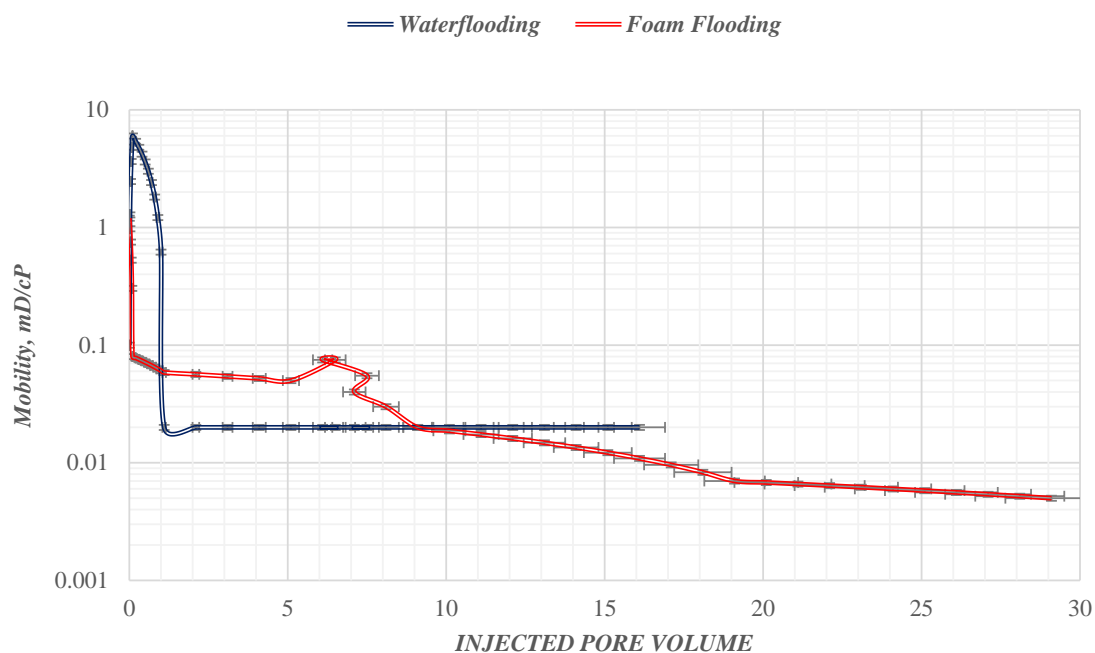


Figure 2. Mobility measurement for two flooding procedure.

3.2. Resistance Factor

Permeability is known as one of the influential parameters to determine the fluid flow mobilization in porous media and to determine the cumulative oil production. In tight reservoirs, this parameter is much lower than its value for conventional reservoirs. The resistance factor is defined as the ratio of foam pressure drop versus brine pressure drop in a steady-state condition. Thereby, due to the lower permeability of tight reservoirs, the foam resistance factor is lower than its value for conventional reservoirs. The utilized foam in the injection processes has the foam quality of 80% and the flow rate of 0.05 cm³/min. According to the results of this study, foam with 80% of foam quality has provided the highest resistance factor. This phenomenon is caused by the low increment of pressure drop in a steady-state condition. The resistance factor in different foam qualities is schematically plotted in Figure 3.

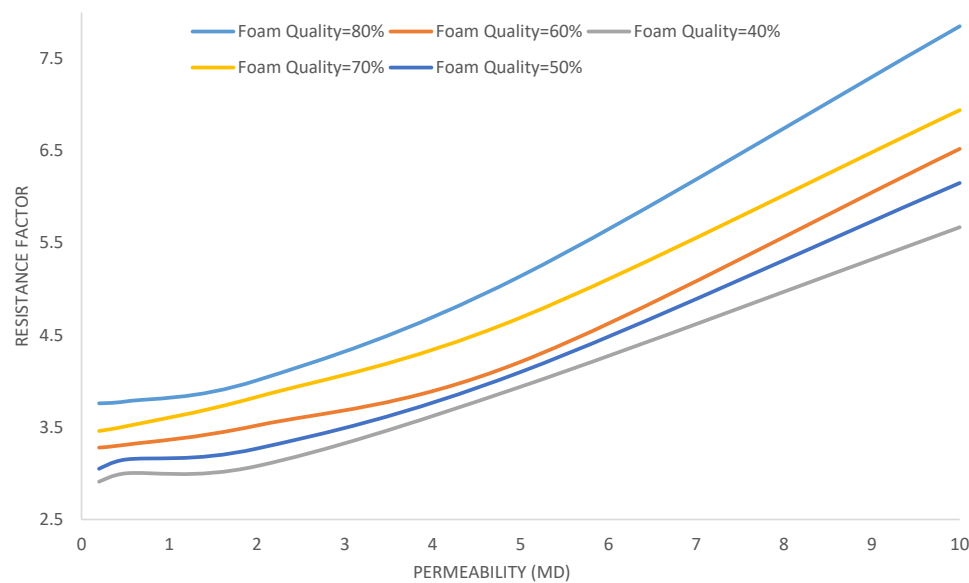


Figure 3. Resistance factor versus permeability in tight reservoirs.

3.3. Pressure Drop

To provide reliable pressure drop measurements, it is essential to measure this parameter throughout the core flooding performances until the fluid flow reaches a steady-state condition. As can be seen in Figure 4, the pressure drop for both waterflooding and foam flooding was plotted to compare the efficiency of each method in tight reservoirs. In the waterflooding process, the pressure drop increased dramatically until the injected pore volume was about 2 PV, and after that, it reached a plateau. In contrast, the pressure drop for foam flooding performances witnessed an increasing pattern with some fluctuations by the increase in pore volume injection. It had its highest value when about 22 pore volume was injected to the core sample. After that, it decreased and reached its lowest value as a constant pressure drop of 20,000 KPa. Therefore, foam flooding would be a more effective method than water flooding on oil recovery enhancement. Moreover, by the interpolation of the pressure drop values and pore volume injections, an equation was obtained to measure the pressure drop approximately. It is shown in Figure 4 as a linear equation.

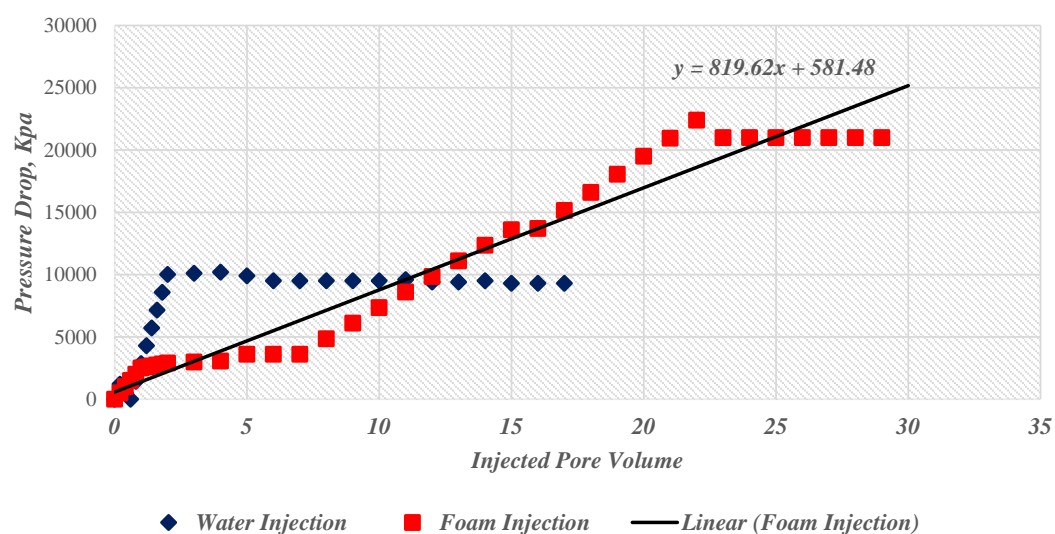


Figure 4. Pressure drop for both injectivity scenarios.

The increase in foam quality caused the pressure drop increase in foam flooding procedures, and pressure drop decrease in brine and gas coinjection performances. As is evident in Figure 5, the gas fraction increase in the core flooding procedures caused the increase in the pressure drop in the brine-CO₂ scenario and decrease in the foam-CO₂ scenario. It means that sequential injection of foams and carbon dioxide would be more efficient than other scenarios, as it provided more pressure drop and more oil recovery from the core samples. It should be noted that the obtained pressure drop in each scenario is in the steady-state condition.

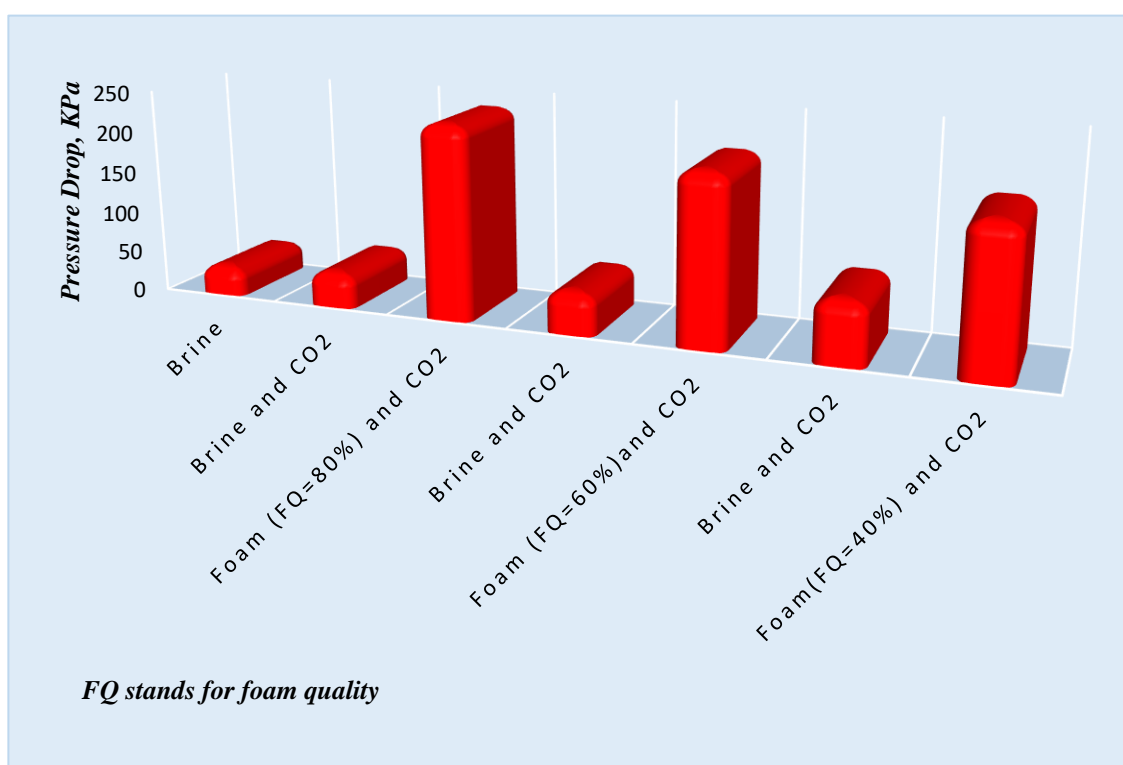


Figure 5. Pressure drop in steady-state condition for different scenarios.

3.4. Recovery Factor

First, coinjection of brine with chemical and thermal methods was taken into consideration to compare each method. As can be seen in Figure 6, foams regarding their mobility reduction provided a higher recovery factor than other scenarios. Between carbon dioxide and nitrogen after brine flooding, as nitrogen has more compressibility than carbon dioxide, it can mobilize more quickly in the pore throats and therefore, the recovery factor for coinjection of nitrogen and brine is higher than for brine and carbon dioxide coinjection. Moreover, nitrogen is more compatible with reservoir characteristics and had less corrosion. According to the results of this experiment, the recovery factor for foams and brine injection is about 80%, while it is relatively 66% and 58% for brine-carbon dioxide and brine-nitrogen, respectively. Consequently, foam injection after water flooding would be an effective method to produce more oil volumes in tight reservoirs.



Figure 6. Recovery factor for different injectivity scenarios.

3.5. Brine Component

In this part of the study, we consider two different brines to compare the effect of each brine in oil production. Figure 7 presents the cumulative oil production for different injectivity scenarios. As is evident, the oil production for all scenarios has approximately the same pattern up to two-pore volume injection. KCl regarding its more significant wettability changes provided more oil production than other scenarios. After two pore volume injections of water with different salinities, foam injectivity started to improve the cumulative oil production. Due to the low wettability changes by formation brine, we witnessed the lower oil production at two-pore volume injection (end of water injection), because the injected water was mobilized through large pores and thereby the oil remained in small channels and pores.

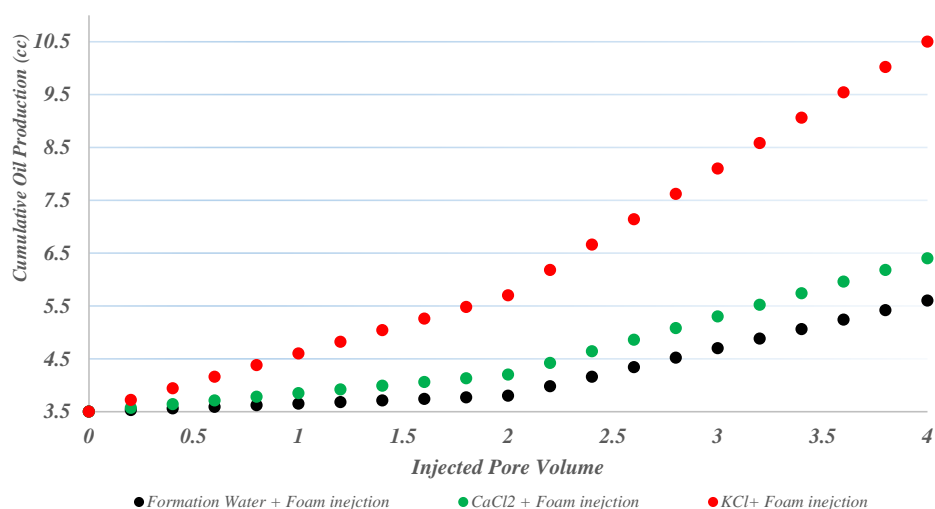


Figure 7. Recovery factor for different brine salinities and Foam injection.

4. Conclusions

In this study, we focused on the application of foams and different brines' component efficiency in the oil recovery enhancement of tight reservoirs. Moreover, due to the low permeability of the tight reservoirs, foam application regarding the unfavorable performance of foams in the porous medium to enhance the oil recovery factor would be a novel solution for petroleum industries to recover greater oil volume from tight reservoirs. As permeability would significantly affect the performances of foams, especially in tight reservoirs, the mobility reduction and resistance factor of the foams are more important in comparison with conventional reservoirs. Therefore, the importance of these two factors would provide a better insight for the petroleum industries during the enhanced oil recovery techniques for tight reservoirs. Foam injection with 80% foam quality provided the highest resistance factor. This phenomenon is caused by the low increment of pressure drop in a steady-state condition. Hence, understanding the efficient foam quality during the enhanced recovery processes would give engineers the chance to concentrate more on the other crucial parameters and instabilities that might affect the performance and economically reduce the vast expenditures of recovery processes. Coinjection of brine-nitrogen, due to the greater compressibility of nitrogen, caused more mobilization of nitrogen in the pore throats and therefore, the recovery factor for coinjection of nitrogen and brine is higher than that of brine and carbon dioxide coinjection. Therefore, the recovery factor for foams and brine injection is about 80%, while it is relatively 66% and 58% for brine-carbon dioxide and brine-nitrogen, respectively. In addition, KCl, regarding its more considerable wettability changes, has provided more oil production than other scenarios.

Author Contributions: M.L.; Data curation, formal analysis, writing—original draft and investigation. C.P.; methodology and project administration; X.H.; Visualization. A.D.; Writing—review & editing, supervision, and validation. All authors have read and agreed to the published version of the manuscript.

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